POTOMAC
ECONOMICS

QUARTERLY INDEPENDENT MONITORING REPORT
ON
DUKE ENERGY CAROLINAS, LLC

First Quarter 2011

Issued by:

Potomac Economics, Ltd.
Independent Market Monitor

CONFIDENTIAL MATERIAL REDACTED

Table of Contents

List of Figures

I. Overview

This transmission monitoring report addresses the period from January 2011 through March 2011 for Duke Energy Carolinas, LLC (formerly Duke Power, a division of Duke Energy Corporation) ("Duke" or "the Company"). For the purpose of increasing confidence in the independence and transparency of the operation of the Duke transmission system, Duke proposed and FERC accepted in Docket No. ER05-1236-00 the establishment of an "Independent Entity" to perform certain OATT-related functions and a transmission monitoring plan that calls for an "independent transmission service monitor". The Midwest ISO was retained as the Independent Entity ("IE"), and Potomac Economics was retained as the independent transmission service monitor.

The scope of the independent transmission service monitor is established in the transmission monitoring plan. The plan is designed to detect any anticompetitive conduct from operation of the company's transmission system, including any transmission effects from the company's generation dispatch. It is also intended to identify any rules affecting Duke's transmission system which result in a significant increase in wholesale electricity prices or the foreclosure of competition by rival suppliers. As stated in the plan:

> The Monitor shall provide independent and impartial monitoring and reporting on: (1) generation dispatch of Duke Power and scheduled loadings on constrained transmission facilities; (2) details on binding transmission constraints, transmission refusals, or other relevant information; (3) operating guides and other procedures designed to relieve transmission constraints and the effectiveness of these guides or procedures in relieving constraints; (4) information concerning the volume of transactions and prices charged by Duke Power in the electricity markets affected by Duke Power before and after Duke Power implements redispatch or other congestion management actions; (5) information concerning Duke Power's calling for transmission line loading relief ("TLR"); and (6) the information provided by Duke Power used to perform the calculation of Available Transmission Capability ("ATC") and Total Transfer Capability ("TTC").

To execute the monitoring plan, Potomac Economics routinely receives data from Duke that allows us to monitor generation dispatch, transmission system congestion, and the Company's response to transmission congestion (both its operational response and its business activities). We also collect certain key data ourselves, including OASIS data and market pricing data.

The purpose of this report is to present the results of our monitoring activities and significant events on the Duke system[1] from January 2011 to March 2011.

A. Independent Monitoring

Potomac Economics performs the monitoring function on a regular basis, as well as performing periodic reviews and special investigations. Our primary monitoring is conducted by way of regular analysis of market data relating to transmission outages, congestion, and system access. This involves data on transmission outages, transmission reservation requests, Available Transfer Capability ("ATC"), transmission line loading relief ("TLR") and curtailments or other actions taken by Duke to manage congestion. Analyses of this data aid in detecting congestion and whether market participants have full access to transmission service.

In addition to the regular monitoring of outages and reservations, we also remain alert to other significant events, such as price spikes, major generation outages, and extreme weather events that could adversely affect transmission system capability and give rise to the opportunity for anticompetitive conduct.

Our periodic review of market conditions and operations is based on data Duke provides, as well as other data that we routinely collect. Our review consists of four parts. First, we evaluate regional prices and transactions to provide an assessment of overall market conditions. Second, we summarize transmission congestion and the use of schedule curtailments in order to detect potential competitive problems. Congestion is identified by schedule curtailments[2] on Duke's transmission system. Third, we evaluate the disposition of transmission service requests and TTC to analyze transmission access and

1 As allowed for in the monitoring plan, certain anomalous findings related to general market conditions, TTC, and transmission outages were shared with Duke to obtain clarification prior to submission to FERC and the state commissions.

2 When we refer to schedule curtailments, we include TLR events because curtailing schedules is the main method used under the TLR procedures to manage congestion.

to detect events on the Duke system that require closer analysis. Finally, to monitor for anticompetitive conduct, we examine periods of congestion and evaluate whether Duke operating activities are consistent with anticompetitive conduct. The operating activities that we evaluate are wholesale purchases and sales, generation dispatch and availability, and transmission availability.

In addition to our periodic reviews, we may from time-to-time be asked to or deem it necessary to undertake a special investigation in response to specific circumstances or events. No such events occurred during the time period of this report.

B. Summary of Quarterly Report

The following subsections summarize the findings of our monitoring of Duke's operations during the quarter.

1. Wholesale Prices and Transactions

Prices. We evaluate regional wholesale electricity prices in order to provide an overview of general market conditions. Over the course of the study period, electricity prices fluctuated between $34 per MWh and $73per MWh and exhibited high correlations with peak load and natural gas prices. There was no sharp price increase during this quarter.

Sales and Purchases. Duke engages in wholesale purchases and sales of power on both a short-term and long-term basis. [redacted]

2. Transmission Congestion

We use TLR events in the vicinity of Duke and schedule curtailments initiated by Duke to identify periods of congestion. Duke manages transmission congestion with generation redispatch, transmission system reconfiguration, and schedule curtailments.[3]

---

3 We use the term schedule loosely in this context. It is actually e-tags that are curtailed. Each e-tag represents a physical sequence and time series of schedules. Therefore, one e-tag may have multiple schedules comprising it. Also, sometimes the same e-tag is curtailed more than once.

Of these, schedule curtailments have the most direct impact on market access and outcomes. Duke reserves and schedules transmission service primarily on a contract-path basis.[4] A common situation in which Duke uses curtailments is when unscheduled firm reservation rights are released to the market and scheduled for non-firm use, but are then displaced when the higher-priority firm reservation holders subsequently submit schedules. The displaced non-firm schedules are curtailed. Curtailments can also occur when the paths reach their contract-path limits even though they may not be heavily loaded with physical flow. During the period of study, there were 15 curtailments initiated by Duke and 28 TLR events in the region. All the TLR events were either initiated by PJM or TVA.

All curtailments regardless of their basis are important because they have the same impact on reducing transmission access. However, only schedules that are curtailed based on physical flow (including TLRs) are potentially influenced by Duke's operation of generation. We analyzed the impact of Duke's generation operations on the flow-based curtailments and do not find that Duke's dispatch of generation contributed to the events.

3. Transmission Access

We evaluate the patterns of transmission requests and their disposition to determine whether market participants have had difficulty accessing Duke's transmission network. If requests for transmission service are frequently denied unjustifiably, this may indicate an attempt to exercise market power. The volume of accepted requests was slightly higher than the previous quarter, and the approval rate was very high, averaging over 99.9 percent over the period of study. Given the high volume of service sold and the low level of refusals, we do not find a pattern in the disposition of transmission requests that indicates restrictive access to transmission.

We identified certain key paths based on the typical volume of refused transmission service requests and the frequency of curtailed transmission schedules on them. These

4 Duke changed to using Available Flowgate Capacity ("AFC") Methodology at the end of March 2011.

paths are those whose "source" or "sink" is either PJM, Duke (DUK), Southern Company (SOCO), Yadkin (YAD), South Carolina Electric and Gas (SCEG), Progress Energy (CPLE and CPLW)[5] or South Carolina Public Service Authority (Santee Cooper or SC). We are also interested in the segments of those paths that have a "source" or "sink" in Duke. We examined TTC calculations on these paths for days when ATC became unavailable. Our review of these days determined that the reductions in TTC were justified based on the day-ahead study results or outages that occurred after the day-ahead studies were run, but there is room for improvement in the accuracy of the day-ahead studies. There is also room for improvement in the process of providing timely notification to the IE of equipment returning to service when its return would increase ATC.

4. Potential Anticompetitive Conduct

Wholesale Sales and Purchases. We examined real-time sales and purchases that were delivered during the period of study. We focus on intra-day bilateral contracts because these best represent the spot price of electricity in markets served by Duke and are the means that Duke would likely use to profit by affecting wholesale electricity prices. Under a hypothesis of market power, we would expect higher sales prices or lower purchase prices during times when transmission congestion arises. Daily average transaction prices ranged between $[redacted] per MWh and $[redacted] per MWh. There were six days when Duke's net sales position could have potentially had a significant benefit from the congestion. We analyzed these days further and did not find evidence of anticompetitive conduct.

Generation Dispatch and Availability. To further evaluate competitive issues, we examined Duke's generation dispatch to determine the extent to which congestion may be caused or exacerbated by uneconomic dispatch. Congestion can occur even when Duke or any other utility dispatches its units in a least-cost manner. Such congestion does not raise competitive concerns. If an unjustified departure from least-cost dispatch ("out-of-

[5] CPLE and CPLW refer to the eastern and western portions of Progress Energy's service territory in North and South Carolina (formally known as Carolina Power and Light).

merit" dispatch) occurs and causes congestion, further analysis is warranted to determine whether the Company's conduct raises competitive concerns.

Using an estimated supply curve, we analyze Duke's actual dispatch to determine whether the actual dispatch departed significantly from what we estimate to be the economic dispatch. We then evaluate the contribution that the out-of-merit dispatch makes to flows on congested transmission paths to determine if congestion was either created and/or exploited by Duke. Our investigation into the congestion events found that generation dispatched out-of-merit order did not have a significant impact on curtailed paths. Consequently, we do not find evidence of anticompetitive conduct. Regardless, we did review the causes of the largest out-of-merit values even though they did not contribute to congestion events; we found that they were caused by justified generation forced outages and derated generators.

We also conducted an analysis of potential economic and physical withholding to further evaluate generation operations. Our measures of potential economic and physical withholding were not indicative of anticompetitive conduct. Evaluation of generation outage rates did not reveal evidence that generation outages were associated with anticompetitive conduct.

Transmission Availability. Finally, we evaluated Duke's transmission outage events in order to determine whether these events may have unduly impacted market outcomes during the study period. We found no evidence of anticompetitive conduct.

5. Conclusions

Our analysis did not indicate any potential anticompetitive conduct from operation of the company's transmission system or generation.

C. Complaints and Special Investigations

We have not been contacted by the Commission or other entities regarding any special investigation into Duke's market behavior, nor have we detected any conduct or market conditions that would warrant a special investigation.

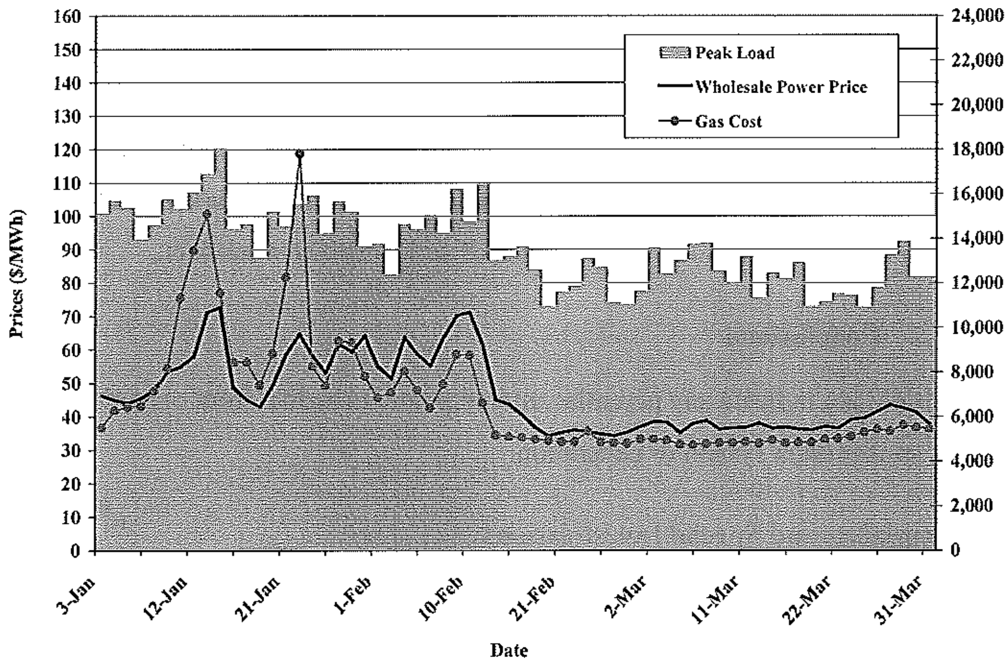
II. WHOLESALE PRICES AND TRANSACTIONS

A. Prices

We evaluate regional wholesale electricity prices in order to provide an overview of general conditions in the market in which Duke operates. Examining price movements can provide insight into specific time periods that may merit further investigation, although they are not definitive indicators of anticompetitive conduct.

Duke is not part of a centralized wholesale market in which transparent spot prices are produced. Wholesale trading in the areas in which Duke operates is conducted under bilateral contracts. Bilateral contract prices are collected and published by commercial data services such as Platts, which we use for this report. Platts publishes prices at various pricing points, including a price for the VACAR (Virginia, Carolinas) sub region of the South East Reliability Council (SERC), which includes Duke's control area. Figure 1 shows the bilateral contract prices for VACAR along with other market indicators.

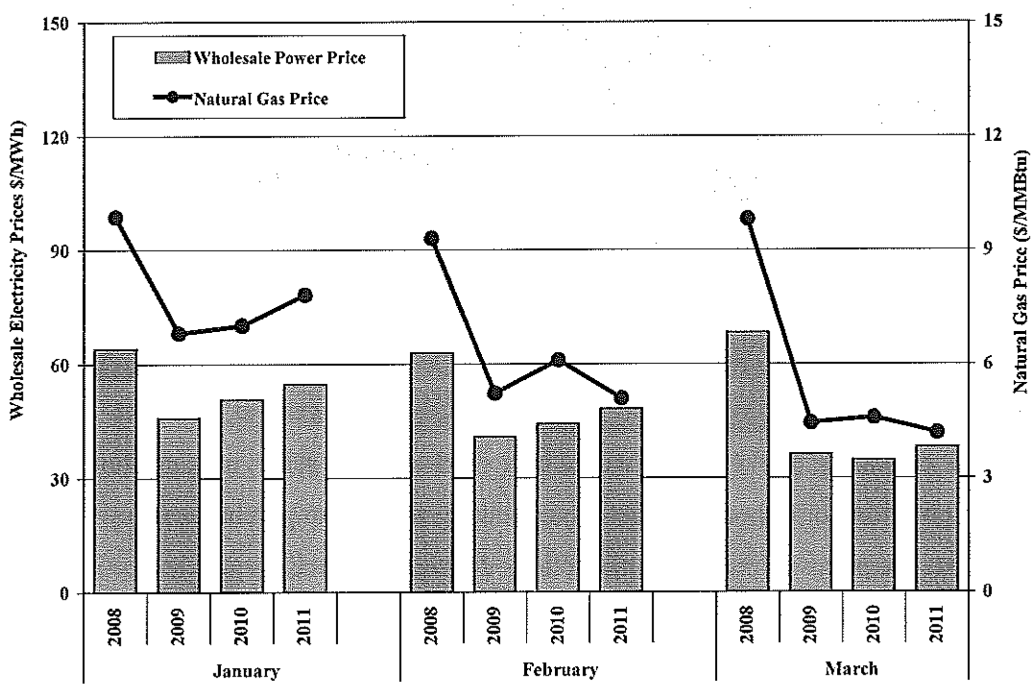
Figure 1: Wholesale Power Prices, Peak Load, and Natural Gas Costs January 2011 – March 2011



We show system load data because of its expected correlation with power prices. We show natural gas cost because natural gas-fired units are most often the marginal unit supplying the grid, and because fuel costs comprise the vast portion of a generating unit's marginal costs. We use the daily price of natural gas deliveries by Transco at its Zone 5 location, a main pricing point for natural gas purchases by Duke. We translate this natural gas cost to a power cost assuming an 8,000 btu/kWh heat rate. This roughly corresponds to the fuel-cost portion of the operating cost of a natural gas combined cycle unit, which should generally correspond to the competitive price for power. Wholesale power prices ranged from $34 per MWh to $73 per MWh over the study period. As the figure shows, electricity prices were stable in the first quarter. Even on the days when gas prices spiked, the electricity prices remained relatively flat.

The next analysis compares the average VACAR power prices for each month in the study period with the corresponding month of the previous three years. Results are shown in Figure 2 together with the average of the daily Transco Zone 5 natural gas prices. As the figure shows, electricity prices have generally been correlated with natural gas prices over time as one would expect.

Figure 2: Trends in Monthly Electricity and Natural Gas Prices January 2008 – March 2011



Overall, our evaluation of wholesale electricity prices in the Duke region did not indicate a time period that merits particular attention based on pricing patterns.

B. Sales and Purchases

Duke engages in wholesale purchases and sales of power. These transactions are both firm and non-firm in nature. Figure 3 summarizes Duke's sales and purchase activity for trades that delivered during the study period. We consider only short-term trades because we are interested in transactions that could have allowed Duke to benefit from any potential market abuse during this time period. Short-term transactions include all transactions that are done in the day-ahead or intra-day markets. Longer-term transactions generally occur at predetermined prices that would not be directly affected by transitory periods of congestion. Additionally, short-term transaction prices are good indicators of wholesale market conditions during periods of congestion.

Figure 3: Summary of Duke Sales and Purchases
January 2011 – March 2011

[redacted]

As the figure shows, [redacted] In general, a market participant exercising market power would be a short-term net seller, making short-term sales at high prices, or a short-term net buyer making short-term purchases at low prices. We evaluate the prices of real-time transactions during congested periods in Section V.A. to detect potential anticompetitive conduct.

III. TRANSMISSION CONGESTION

A. Overview

Duke is located in the SERC region of the North American Electric Reliability Council ("NERC"). NERC is certified as the Electric Reliability Organization ("ERO") in the United States as of July 20, 2006. SERC is divided geographically into five sub-regions that are identified as Entergy, Gateway, Southern, TVA, and VACAR. VACAR is further divided into two intraregional coordination groups including VACAR North and VACAR South for the establishment of Reliability Coordinators ("RC"). Duke is within the VACAR South coordination group along with five other balancing authorities: Progress Energy Carolinas, Inc., South Carolina Electric & Gas Company, South Carolina Public Service Authority (Santee Cooper), Southeastern Power Administration, and Yadkin (a division of Alcoa Power Generation Inc).

Procedures to manage transmission congestion are implemented by the VACAR South Reliability Coordinator. The activities covered in these procedures include performing day-ahead and real-time reliability analysis, working with participants to correct System Operating Limit ("SOL") and Interconnection Reliability Operating Limit ("IROL") violations, and managing TLR events.

The VACAR South Reliability Coordinator utilizes an "Agent" to perform Reliability Coordination tasks. Duke, in addition to being a member of the VACAR South coordination group, is contracted to serve as Agent to perform the duties of Reliability Coordinator for itself and the other five VACAR South member companies. The transmission monitoring plan calls for monitoring Duke's operation of its transmission system to identify anticompetitive conduct, including conduct associated with system operations and reliability coordination.[6] Our monitoring of such conduct is limited to conduct associated with Duke's transmission system and does not extend to Duke's activities as Agent for the VACAR South Reliability Coordinator.

[6] See Transmission Service Monitoring Plan, Section 1.2.

B. Transmission Congestion

We monitor Duke for potential anticompetitive operation of generation or transmission facilities that may create transmission congestion or otherwise create barriers to rival companies' access to the markets. Duke identifies congestion in the operating horizon through real-time contingency analysis ("RTCA"). In this process, operators monitor line-loadings to keep them within ranges whereby a system outage or "contingency" can be safely sustained. If the line-loadings exceed this safe range (called the system operating limit or "SOL"), then the lines are relieved[7] through generation redispatch, reconfiguration, schedule curtailments, and/or load reduction.[8]

Congestion between balancing authorities is monitored and managed through the use of TLR procedures. These procedures invoke schedule curtailments, system reconfiguration, generation redispatch, and load shedding as necessary to relieve congestion by reducing flows below the first-contingency transmission limits on all transmission facilities. Duke's general practice is to curtail schedules and redispatch generation as needed to manage congestion without invoking TLR procedures, but Duke can impact or be impacted by TLR events invoked by neighboring areas.

Schedule curtailments can constitute anticompetitive conduct if they are not justified. They cause an immediate reduction in market access that could affect market outcomes. Accordingly, these congestion events are the basis for our screening of Duke's generation and transmission operations.

For the purposes of our analysis, we consider two types of schedule curtailments. One we refer to as "flow-based curtailments", which are curtailments to accommodate the actual physical flows on facilities as identified by the RTCA. We include TLR events[9] as flow-based curtailments. The other is "contract-path-based curtailments" which are not related to physical flows but rather to contract path limits. Contract-path-based schedule curtailments may be implemented to stay within contract limits even though the path may

7 Some contingency overloads do not require action to be taken because they do not have the potential to cause cascading outages, substantial loss of load, or major equipment damage.

8 System reconfiguration actions may include opening tie line breakers, which can cause TTC to go to zero and induce schedule curtailments.

9 The types of TLR events that we include are 3a, 3b, 5a and 5b.

not be at its physical limit. While contract-path-based curtailments have the same effects on market access as flow-based curtailments, these curtailments are not caused by the operation of generation.

Contract-path-based curtailments are implemented when transmission conditions reduce total transfer capability below the level of existing schedules on the contract path, which results in the curtailment of non-firm and possibly firm schedules. Contract-path-based curtailments are also the result of non-firm service being displaced to accommodate a schedule under a firm reservation. Since these conditions are not affected by generation operations, we only use the flow-based curtailments in our analysis of generation operations.

During the period of study, there were 15 curtailments initiated by Duke, which were all contract-path based curtailments. There were 28 TLR events in the region. Three of the events were initiated by PJM and the remaining twenty-five were initiated by TVA. The TVA events were primarily driven by outages that TVA was taking on the 500 kV transmission system in its area.

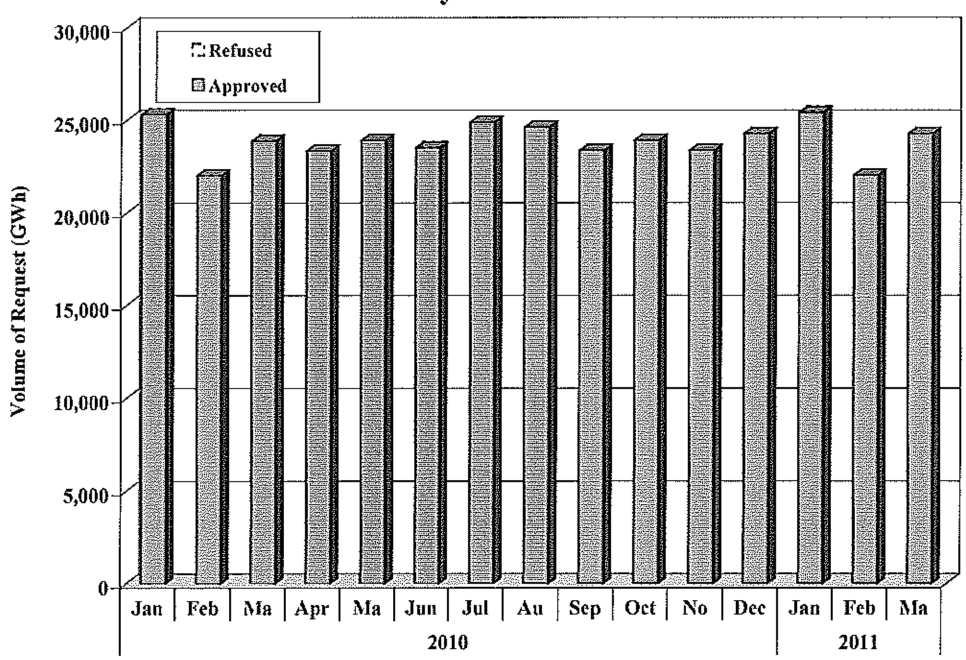
IV. Transmission Access

A main component of the transmission monitoring function is to evaluate transmission availability on the Duke system. In this section, we evaluate access to transmission by analyzing the disposition of transmission service requests. The patterns of transmission requests and their disposition are helpful in determining whether market participants have had difficulty accessing Duke's transmission network.

In order to make this evaluation, we calculate the volume of requested capacity that spanned the time period under study. For example, if a request was approved in January for service in June, we categorize that as an approval for June. Because requests vary in magnitude and duration, we assign a total monthly volume (GWh) associated with a request, which provides a common measure for all types of requests. Hence, a yearly request for 100 MW has rights for every hour of the month for which the request spans, just a like a monthly request. A request covering less than the entire month is assigned the hours between its stop and start date.

Figure 4 shows the breakdown of transmission service requests in each month from January 2010 through March 2011 and summarizes the disposition of the requests.

Figure 4: Disposition of Requests for Transmission Service on the Duke System January 2010 - March 2011



Total volumes of approved requests during the period have increased slightly from the same quarter last year and from the prior quarter. Although the refused volumes are too small to be visible in the figure, the refusal volume was only 48.2 GWh during the first quarter of 2011, which is an increase from the refusal volume of 12.7 GWh during the same quarter last year and an increase from the refusal volume of 3.1 GWh during the fourth quarter of 2010. The approval rate of transmission service requests was very high over the study period, averaging over 99.9 percent. Given the high volume of approved requests and the low volume of refused requests, we do not find evidence that Duke has restricted access to transmission capability.

To evaluate the disposition of transmission requests further, we compare the volume of transmission requests over the study period by increment of service to the requests from the corresponding period a year prior. This comparison is shown in Figure 5.

Figure 5: Disposition of Transmission by Duration of Service

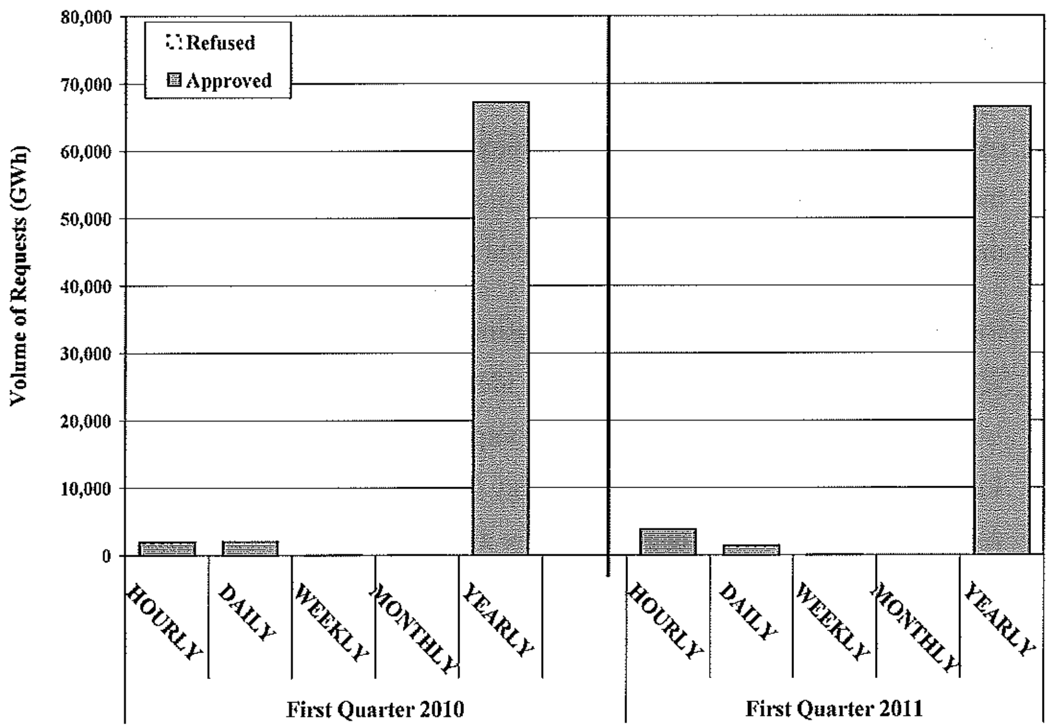


Figure 5 indicates a slight increase in the approval of hourly services and a small increase in the approval of weekly services. There were decreases in the approvals of the daily, monthly and yearly services. This shows a slight overall increase in approvals with a shift to hourly service. The volume of refusals is too small to be visible in the figure. These increases in approval volumes and 99.9% approval rate support the conclusion that transmission access has not become more restrictive.

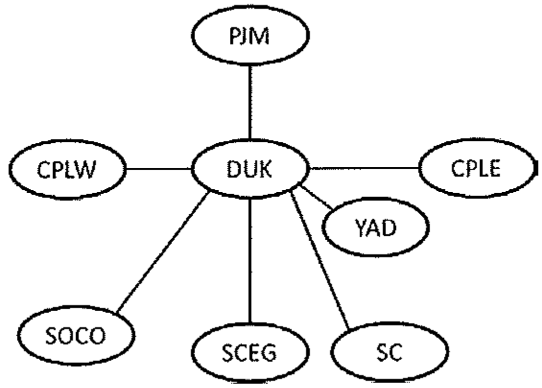
Our next analysis focuses on TTC for key contract paths. We assess TTC reductions that may limit market access. As mentioned above, Duke's primary means of managing congestion within its system is to forecast congestion using day-ahead studies.[10] When congestion is forecasted, the TTC is reduced in order to cause schedule curtailments in the operating horizon. The day-ahead study is conducted by the IE using data provided by Duke. The study can result in reductions in TTC on certain paths. To avoid curtailing firm schedules, TTC is not reduced below firm schedule amounts even if the day-ahead studies predict congestion at those levels.

This process creates an incentive for Duke to provide forecasts that reduce TTC and thereby exclude competitors. Therefore, we monitor this process by selecting cases where competition may be impacted adversely, namely, cases where non-firm ATC was at or near zero. We then review the TTC associated with these cases to determine whether a reduction of TTC could have caused the non-firm ATC to be at or near zero. Such a result would raise concerns of potentially anticompetitive behavior. Thus, if it arises, we make further examination to determine if the reduction in TTC was justified. We monitor this process at two levels. First, we simply check the day-ahead study results to ensure the process is being implemented properly. Then we assess the accuracy of the process if the congested elements are on Duke's transmission system.

Based on the volume of refused transmission service requests ("TSRs") and the frequency of schedule curtailments typically seen, we identify the key paths as those whose "source" or "sink" is either PJM, Duke (DUK), Southern Company (SOCO), Yadkin (YAD), South Carolina Electric and Gas (SCEG), Progress Energy (CPLE and CPLW) or South Carolina Public Service Authority (Santee Cooper or SC). We are also interested in the segments of those paths that have a "source" or "sink" in Duke. These key paths are shown in Figure 6 below. We identify the limiting segments of these paths for further review.

[10] The accuracy of day-ahead studies is limited due to the studies being based on uncertain parameters such as system load and interchange.

Figure 6: Key Paths



Of the key paths, the segments of "Duke to PJM", "Duke to SOCO", "Duke to SC" and "Duke to SCEG "had instances of near zero Non-Firm ATC coincident with TTC reductions. These path segments are candidates for further review because days when the non-firm ATC was at or near zero coincident with a reduction in TTC may represent Duke improperly reducing TTC in order to reduce competitors' market access. The minimum TTC and non-firm ATC for each day for these path segments are shown in Figure 7 through Figure 10 below.

Figure 7: DUK to PJM Daily Minimum of Hourly Capacity
January 2011 – March 2011

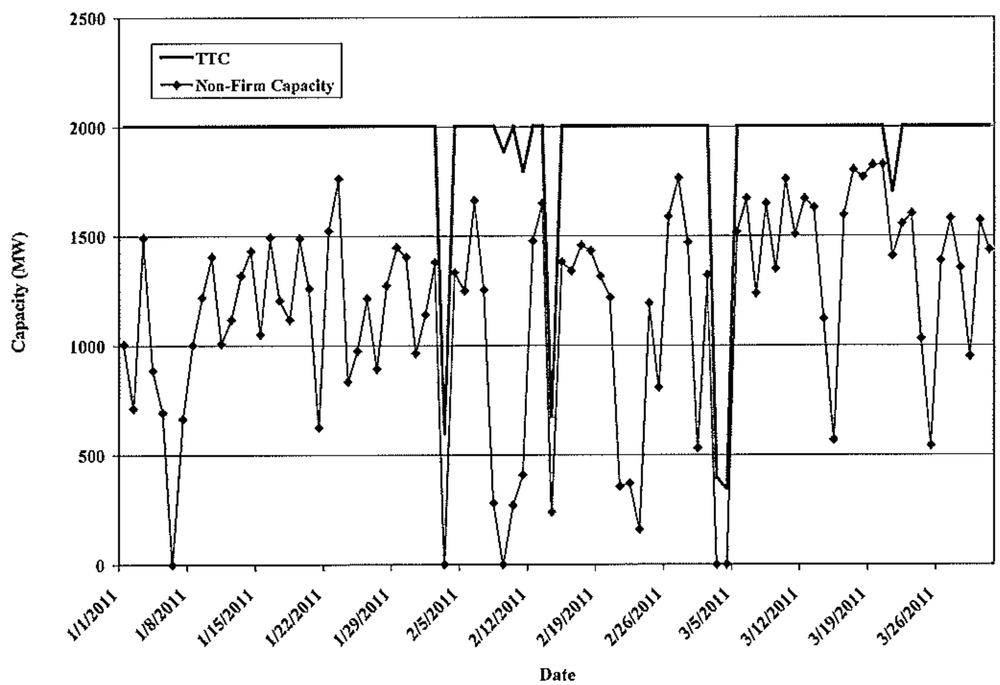


Figure 8: DUK to SOCO Daily Minimum of Hourly Capacity
January 2011 – March 2011

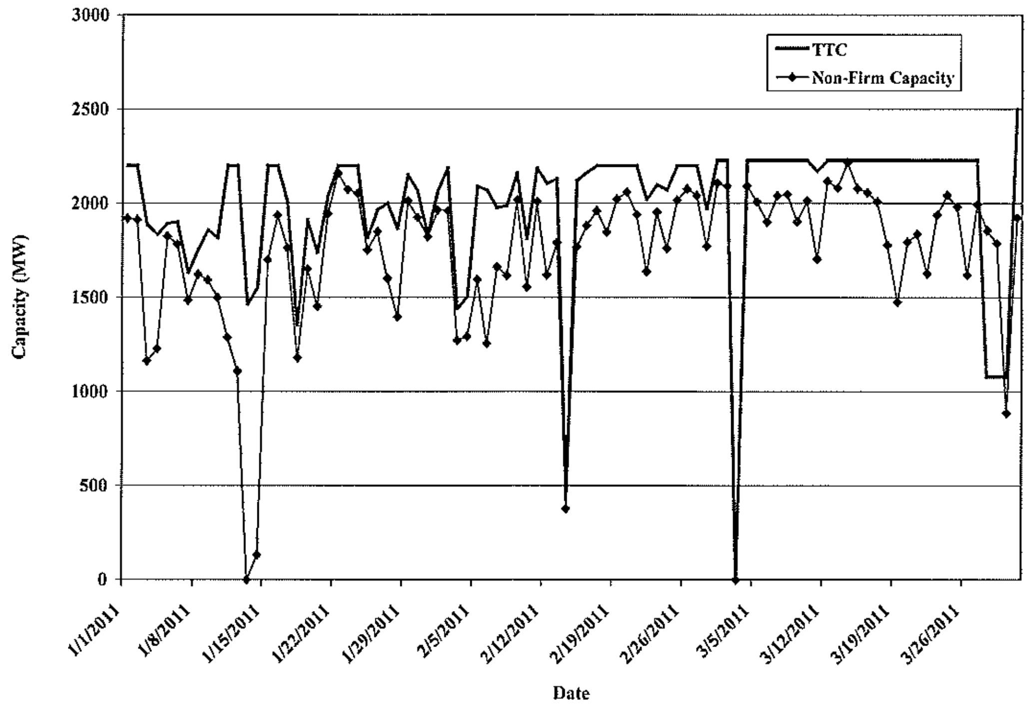


Figure 9: DUK to SC Daily Minimum of Hourly Capacity
January 2011 – March 2011

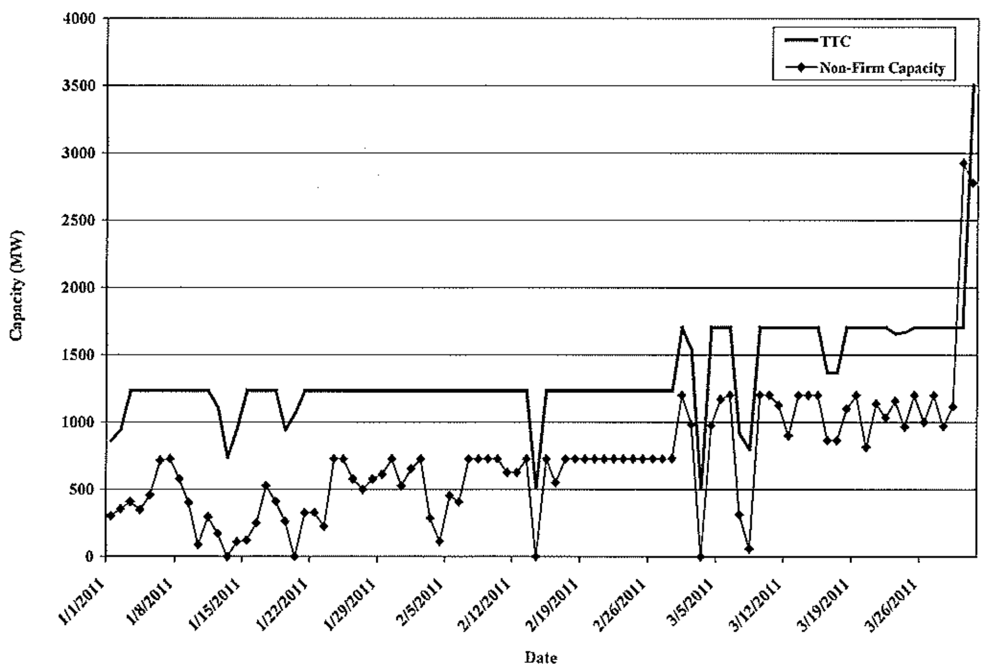
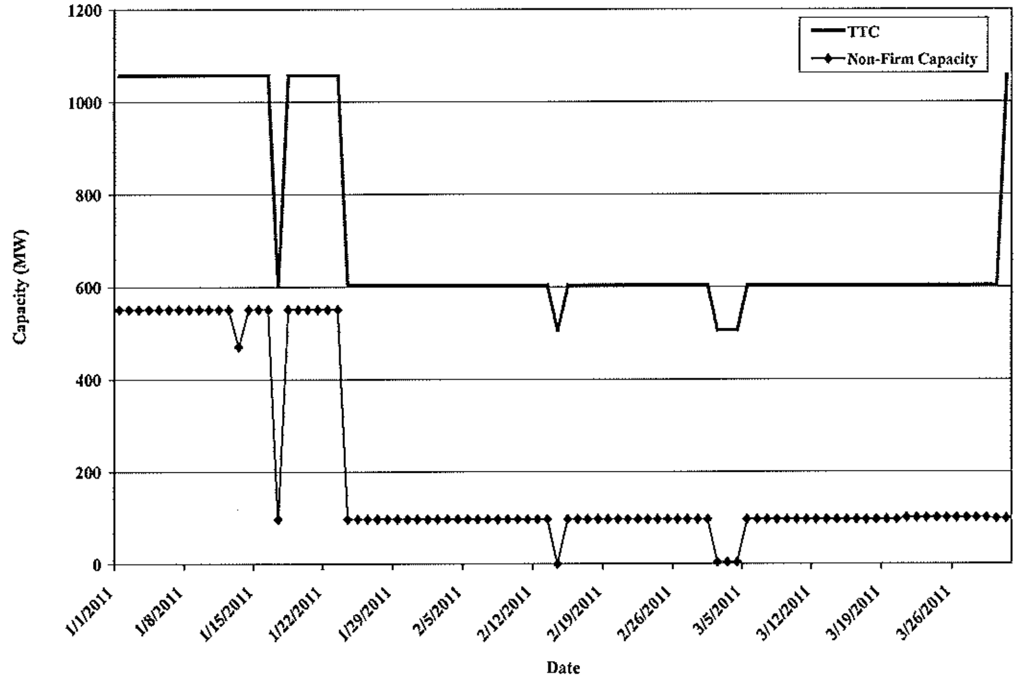


Figure 10: DUK to SCEG Daily Minimum of Hourly Capacity
January 2011 – March 2011



The four path segments shown in Figure 7 through Figure 10 above experienced TTC reductions based on constraints binding in the day-ahead studies. To determine whether the reduced TTC values were properly invoked, we sought to confirm that the four path segments had TTC postings consistent with the day-ahead studies and the business practices. We found that two of the four path segments had TTC postings consistent with the day-ahead study results and the business practices. The two non-conforming posting were the Duke to PJM path and Duke to SCEG path on March 4. On this date, the TTC postings were revised to reflect the return to service of the [redacted], but the IE was not notified of the line returning to service until they inquired thirteen hours after-the-fact. During this time, the "Duke to PJM" path TTC was at 346 MW instead of 2003 MW and the "Duke to SCEG" path TTC was at 506 MW instead of 603 MW. We recommend that Duke improve the process of providing timely notification to the IE of equipment returning to service when its return may increase ATC. However, in this case, we found that there were no schedule curtailments, TSR refusals, or TLRs associated with this event.

Next, we analyze the accuracy of TTC reductions by determining whether the conditions predicted in the day-ahead studies actually occurred in the real-time. We focus on the days when there were either TSR refusals or schedule curtailments associated with the TTC reductions. It is on these days that competition may be affected.

- *January 13, PJM to SOCO:* Non-firm schedules were curtailed and TSRs were refused on the "PJM to SOCO" path due to a TTC reduction caused by a constraint on the "Duke to SOCO" segment. The specific constraint was '[redacted] The constraint limited the TTC to 1,466 MW. The constraint was binding due to the impact of the outage of th[redacted]

- February *3, "Duke to PJM" and "SOCO to PJM":* TSRs were refused due to a TTC reduction caused by a constraint on the "Duke to PJM" segment. The specific constraint was [redacted]". The constraint limited the TTC to 598 MW based on a contract path limit. The constraint bound due to the impact of the outage of the [redacted].

- *March 3, "Duke to PJM" and "SOCO to PJM":* Non-firm schedules were curtailed due to a TTC reduction caused by a constraint on the "Duke to PJM" segment. The TTC was limited by the Progress Energy constraint '[redacted] Though the modeled constraint limited the TTC to -75 MW, Duke only reduced the TTC to 396 MW, which was the level of the Transmission Reliability Margin (TRM) plus firm transmission rights. The purpose of this was to avoid the curtailment of firm schedules unless needed in the real-time. The constraint bound due to the impact of the outage of the [redacted] The "SOCO to PJM" path is an example where flow on one segment (SOCO to Duke) relieves the constraint while flow on the other segment (Duke to PJM) loads the constraint, but the net effect is not reflected. Next quarter, when Duke begins using AFC methodology, the effects will be combined for these types of paths.

- *March 3, Duke to SOCO:* Non-firm schedules were curtailed on the "Duke to SOCO" path due to a TTC reduction caused by a Progress Energy constraint [redacted] Though the modeled constraint limited the TTC to -454 MW, Duke only reduced the TTC to 15 MW, which was the level of the Transmission Reliability Margin (TRM) plus firm transmission rights. The purpose of this was to avoid the curtailment of firm schedules unless needed in the real-time. The constraint was binding due to the impact of the outage of the [redacted]

For each of the four instances above, we are interested in the accuracy of the TTC values. However, only the first instance is a Duke constraint based on flow limits. The February 3 instance is based on a contract path limit and the two March 3 instances are based on a Progress Energy constraint rather than a Duke constraint. The first instance is limited by the [redacted] constraint. We determine the accuracy by comparing day-ahead study conditions to actual real-time conditions. First we checked to see if the constraint appeared as a violation in the real-time contingency analysis data. Because it did not appear, we proceeded to analyze real-time flow data. We found that the maximum flows were 55 percent, of the operating limit for January 13, which indicates that the day-ahead study was not an accurate predictor of real-time conditions for this event. Due to the uncertainties of forecasts that are the basis of the day-ahead studies, some inaccuracies are expected and should not be considered anticompetitive. This level of departure between the real-time results and the day-ahead study are within reasonable expectations and so, we do not consider the result raise anticompetitive concerns.

Our review of Duke's activity relating to reducing TTC shows some room for improvement in the process of providing timely notification to the IE of equipment returning to service when it increases ATC. It also shows room for improvement in the accuracy of the day-ahead studies. However, we do not find that transmission access was limited in an anticompetitive manner.

V. Monitoring for Anticompetitive Conduct

In this section, we report on our monitoring for anticompetitive conduct. The market monitoring plan calls for identifying anticompetitive conduct, which includes conduct associated with the operation of either Duke's transmission assets or its generation assets that can create transmission congestion or erect barriers to rival suppliers, thereby raising electricity prices. To identify potential concerns, we analyze Duke's wholesale sales in the first subsection below, its dispatch of generation assets in the second subsection, and Duke's transmission operations in the third subsection.

A. Wholesale Sales and Purchases

We examine transaction data to determine whether the prices at which Duke sold or purchased power may raise concerns regarding anticompetitive conduct that would warrant further investigation. We are particularly interested in periods when transmission congestion arises. If Duke were engaging in anticompetitive conduct to create congestion, it could potentially benefit by making sales at higher prices in constrained areas or purchases at lower prices adjacent to constrained areas. We examined the real-time bilateral transactions made by Duke using Duke internal records. We focus on real-time transactions because anticompetitive conduct is likely to be more successful in the real-time market.

Competition is facilitated by the ability of rivals to gain market access by reserving and scheduling transmission service. Access will be limited if ATC is unavailable, transmission requests are refused, or schedules are curtailed. Curtailments are also an indicator of congestion because they can be made when a path is over-scheduled or physically overloaded. If Duke's ability to curtail schedules is being abused, we would expect to see systematically higher prices for sales or lower prices for purchases coincident with curtailments.

Recall that curtailments can be flow-based (i.e., the result of flows exceeding the system operating limit), or contract-path-based (i.e., the result of contract-path reservations exceeding the path rating). For our analysis of Duke's sales, we use both types of curtailments. This is reasonable because both types of curtailments reduce market access. Moreover, Duke has the direct ability to affect both flow-based curtailments and contract-path-based curtailments. It can affect flow-based curtailments through operating activities and it can affect contract-path-based curtailments by unjustifiable schedule reductions. By screening the curtailment data against sales activities, we can focus attention on events that merit further inquiry. In particular, we monitor any link between curtailments and Duke's position in the real-time markets that could have potentially benefited from the curtailments. To monitor this, we calculate a measurement called the maximum daily effective market position ("Max Effect"). The Max Effect indicates Duke's trade volume that could have potentially benefited from a particular curtailment. Days with curtailments coincident with high Max Effect levels are days when the curtailments could have potentially allowed Duke to exploit the effect of the curtailment. These days are further evaluated to determine if the transactions were done at pricing levels that are consistent with a pattern of anticompetitive conduct.

The Max Effect is calculated in two steps. First, for each hour and for each constraint and delivery point, we calculate a shift-factor-weighted [11] volume of trades by summing the product of the shift factors and the net trade volumes (purchases minus sales). For each hour and each constraint, the values are summed across all delivery points. Second, from this set of values, we select the maximum value for each day. If the maximum value is positive, we evaluate it more closely.

Figure 11 shows the daily average prices received by Duke for real-time sales and purchases. The blue shading indicates days when curtailments occurred that were potentially beneficial to Duke's positions in the real-time markets.

[11] The relationship between constrained paths and market delivery points is determined through shift factors, which are the portion of power injected at the market delivery point that flows over the constrained transmission path. Shift factors between -.01 and .01 are set to zero.

Figure 11: Prices for Duke Sales and Purchases
January 2011 – March 2011

[redacted]

The weighted average daily prices of Duke's sales range between $[redacted] per MWh and $[redacted] per MWh. The volume-weighted average daily sales price was $[redacted] per MWh. On days with curtailments that may have benefited Duke's net sales position, the average sales price was $[redacted] per MWh. The weighted average daily prices of Duke's purchases range between $[redacted] per MWh and $[redacted] per MWh. The volume-weighted average daily purchase price was $[redacted] per MWh. On days with potentially beneficial curtailments, the average purchase price was $[redacted] per MWh. Because the transaction prices when the system was congested were more favorable to Duke as a seller than average prices over the period of study, we are more concern about seller market power. Thus, we look further into days with high sales prices as well as days with Max Effect over 50 MW.

There were instances of high priced sales on [redacted]. These were not associated with curtailments. Duke's response to our questions on these transactions was that these days correspond to periods of time when Duke had significant capacity in outage (as can be seen in Figure 15). Duke needs to use the remaining in service capacity to support its non-firm purchases. In order to manage the economic risk of making these sales, the price was based on the cost of operating oil peaking units. We find this to be reasonable behavior.

[redacted] Duke had multiple sales to PJM and the Midwest ISO and one purchase from PJM in the hour when the Max Effect was the greatest. The highest sales price was $[redacted] per MWh which is relatively low when compared with other days during that time. At the same time, a TLR was declared on flowgate [redacted] Because the TLR was initiated by TVA and the sales price is relatively low, it does not raise competitive concerns.

[redacted] Duke has one sale to PJM for [redacted] MW at a price of $[redacted] per MWh during the hour when the Max Effect is the greatest. At the same time, a TLR was declared on flowgate [redacted] Since the TLR was initiated by PJM, it does not raise competitive concerns. However, the sales price was high compared to neighboring days.

[redacted] Duke has one sale to PJM for [redacted] MW at a price of $[redacted] per MWh when the Max Effect is the greatest. At the same time, a TLR was declared on flowgate [redacted] Since the TLR was initiated by TVA, it does not raise competitive concerns. However, the sales price was high compared to neighboring days.

In the next sections on the review for anticompetitive conduct, we will pay particular attention to activities on [redacted] to ensure that the constraints noted above as potentially beneficial to Duke's purchase and sales positions were not caused by anticompetitive operation of generation or transmission assets.

B. Generation Dispatch and Availability

To further evaluate whether Duke's conduct raises any anticompetitive concerns, we examine the company's generation dispatch to determine the extent to which congestion may have been the result of uneconomic dispatch of generation by Duke. We conduct two analyses. We first determine the hourly quantities of out-of-merit dispatch and the degree to which the out-of-merit dispatch contributed to flows on congested transmission paths. If the contribution is significant, further investigation of these times may be warranted. We use flow-based curtailments because, as explained more below, these types of curtailments (as opposed to contract-path-based curtailments) are the ones that would result from unjustified out-of-merit dispatch. Second, we examine the "output gap", which measures

12 [redacted]

the degree to which Duke's generation resources were not fully scheduled when prevailing prices exceeded the marginal cost of running the unit.

1. Out-of-Merit Dispatch and Curtailments

Congestion can be a result of limits on the transmission network when utilities dispatch their units in a least-cost manner. This kind of congestion does not raise competitive concerns. If a departure from least-cost dispatch ("out-of-merit" dispatch) is unjustifiable and causes congestion, it raises potential competitive concerns.

We pursue this question by measuring the out-of-merit dispatch on the Duke system. In our analysis, we consider a unit to be out-of-merit when it is dispatched when a lower-cost unit is not fully loaded at the same time. To identify out-of-merit dispatch, we first estimate Duke's marginal cost curve or "supply curve".[15] We use incremental heat rate curves, fuel cost, and other variable operations and maintenance cost data provided by Duke to estimate marginal costs. This allows us to calculate marginal costs for Duke's units. We order the marginal cost segments for each of the units from lowest cost to highest cost to represent the cost of meeting various levels of demand in a least-cost manner. For our analysis, the curve is re-calculated daily to account for fuel price changes, planned maintenance outages, and planned deratings.

Figure 12 shows the estimated supply curve for a representative day during the time period studied.

[15] We use the term marginal cost loosely in this context. The value we calculate is actually the *marginal running cost* and does not include opportunity costs, which may include factors such as outage risks or lost sales in other markets.

Figure 12: Duke Supply Curve

[redacted]

The dispatch analysis excludes nuclear and hydro units because their operation is not primarily driven by current system marginal operating costs. Nuclear resources rarely change output levels and the opportunity costs associated with hydroelectric resources make it difficult to accurately estimate their costs.

As the figure shows, the marginal cost of supply increases as more units are required to meet demand, as expected. The highest marginal cost is over $[redacted] per MWh. We use each day's estimated marginal cost curve as the basis for estimating Duke's least-cost dispatch for each hour in the study period.

In general, this will not be completely accurate because we do not consider all operating constraints that may require Duke to depart from our estimate of least-cost dispatch. In particular, this analysis does not model generator commitments, assuming instead that all available generators are online. Consistent with this assumption, we limit the hours in this analysis to only include those in-between the morning ramp and the evening ramp to avoid the distortions caused by generation commitments and de-commitments. While market monitoring resources could have been expended to refine the estimated generator commitment and dispatch to make it correspond more closely to actual operating parameters (i.e., start costs, run-time and down-time constraints, etc.), we believe this simplified incremental-operating-cost approach is adequate to detect instances of significant out-of-merit dispatch that would have a material effect on the market.

When a unit with relatively-low running costs is justifiably not committed, our least-cost dispatch will overstate the out-of-merit quantities because it will identify the more expensive unit being dispatched in its place as out-of-merit. This may result in higher levels of out-of-merit dispatch during low-load periods when it is not economic to commit certain units.

Other justifiable operating factors that cause the out-of-merit dispatch to be overstated are energy limitations and ancillary services. An example of an energy limitation is a coal delivery problem that prevents a coal plant from being fully utilized. Because the coal plant is still capable of operating at full load for a shorter time period, the condition does not result in a planned outage or derating. The necessity to operate the plant at reduced load to conserve coal can cause the out-of-merit values to be overstated.

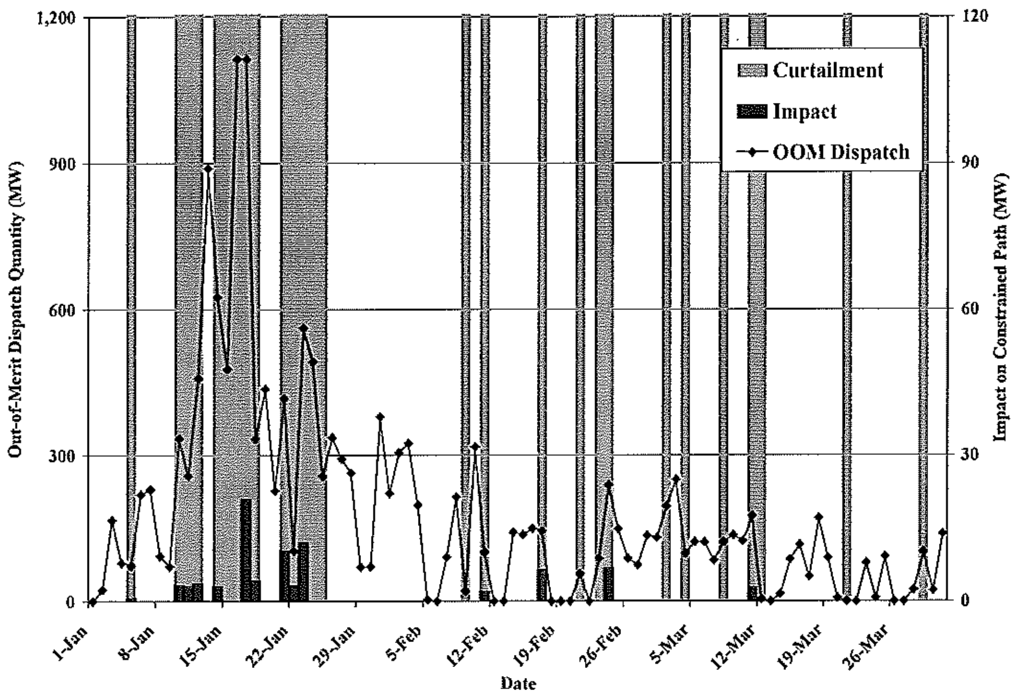
Ancillary services requirements such as spinning reserves, system ramp rate limitations, and AGC control requirements can make it operationally necessary to dispatch a number of units at part load rather than having the least expensive unit fully-loaded. These operational requirements can cause the out-of-merit values to be overstated. The out-of-merit quantities include units on unplanned outage since a sudden unplanned outage may be an attempt to uneconomically withhold generation from the market.

Overall, our analysis will tend to overstate the quantity of generation that is truly out-of-merit. Accordingly, the accuracy of a single instance of out-of-merit dispatch is not as important as the trend or any substantial departures from the typical levels.

In our analysis, we seek to identify days with significant out-of-merit dispatch that coincides with transmission congestion. Congestion is indicated by flow-based schedule curtailments. Flow-based curtailments are those that are taken close to real-time in order to prevent physical flows from exceeding system operating limits. Out-of-merit dispatch can be used to affect these flows and create the need for curtailments, potentially limiting competition in specific locations. Contract-path-based curtailments, on the other hand, are the result of reserved rights on the contract paths and are unaffected by real-time dispatch.

Figure 13 shows the daily maximum "out-of-merit" dispatch for the peak hours of each day in the study period.

Figure 13: Out-of-Merit Dispatch and Congestion Events January 2011 – March 2011



Also shown in the figure are 27 days with flow-based curtailments represented by blue bars. On 19 days, the out-of-merit dispatch increased flows on curtailed paths. The largest impact was 21 MW, which we find to be insignificant. Moreover, because the out-of-merit dispatch did not significantly increase the flow on the congested transmission elements, we do not find this to be evidence of anticompetitive conduct.

There was a two-day spike in out-of-merit dispatch that exceeded 1,000 MW starting on January 16, 2010. We address this spike because it stands out in the exhibit. The [redacted] was in an unscheduled outage due to [redacted]. The outage started late on January 15 and ended on January 18. There is no evidence of anticompetitive conduct because the outage is justified and did not contribute to curtailments.

2. Output Gap

The output gap is another metric we use to evaluate Duke's generation dispatch. The output gap is the unloaded economic capacity of an available generation resource. The capacity is economic when the prevailing market price exceeds the marginal cost of producing from that unit by more than a specified threshold. We use $25 per MWh and $50 per MWh as two thresholds in our analysis. Hence, at the $25 per MWh threshold, if the prevailing market price is $60 per MWh and a unit with marginal costs of $40 per MWh is unloaded, then we do not consider this part of the output gap because the marginal cost plus the $25 per MWh threshold is greater than the $60 per MWh market price. However if the marginal cost is $30 per MWh, we would consider it in the output gap at the $25 per MWh threshold, but not under the $50 per MWh threshold. This quarter, there were nine output gap events at the 25 MW threshold as shown in Figure 14.

We analyze the market for the 16-hour daily on-peak power product, because this is the most liquid market in the VACAR South region and it is where market power would be the most profitable. We also analyze the 16-hour on-peak average of the hourly PJM real-time market prices, because it is the most liquid real-time market in the region. We compare these prices to the marginal cost of each generator. The daily output gap for each generator is expressed as the output gap for the hour when the generator reaches its peak output level for the day. The results are the sum of the daily output gap of the included generation. Only units that are committed during the day are included in the daily calculation. Hydro and nuclear units are also excluded because nuclear resources rarely change output levels in response to market conditions for a variety of reasons and the opportunity costs associated with hydroelectric resources make it difficult to accurately estimate their costs.

Figure 14: Minimum Daily Output Gap
January 2011 – March 2011

[redacted]

As stated above, we analyze two sources of data that may be representative of prevailing power prices; the Platts VACAR index and the PJM market prices. The above figure shows that output gap events occurred on eight days at the $25 per MWh VACAR threshold and one day at the $25 per MWh PJM threshold. The highest VACAR index output gap event was for 52 MW and the highest PJM index output gap was for only 24 MW, which are insignificant for a system of this size. The 52 MW output gap is comprised of small amounts of capacity spread over eleven different units. We do not find evidence of anticompetitive conduct through the withholding of generation.

3. Generator Availability

We evaluate generator availability by examining the amount of capacity on outage as well as the ratio of capacity on outage to total capacity. Our first analysis is in Figure 15. We compare the daily average capacity on outage during the on-peak hours as well as the VACAR price and the prices at which Duke made real-time sales.

Figure 15: Outage Quantities
January 2011 – March 2011

[redacted]

Our main interest is in unplanned generation outages that cause increases in market prices. The figure shows that there were high outage volumes that were coincident with significant increases in Duke's sales prices on [redacted] We requested additional information on the individual unplanned unit outages and found the following:

- [redacted]
- [redacted]
- [redacted]
- [redacted]
- [redacted]

The affected capacity from the above outages sum to [redacted] as shown in the figure. Based on our review, we find these outages to be justified.

The correlation between outages and prices is not immediately apparent from the chart. Therefore, we present statistics in Figure 17 to help clarify the relationship.

Figure 16 shows the average ratio of capacity in outage to total capacity (i.e. the average outage rate) and the VACAR price and the Duke short-term sales price. This chart reveals patterns similar to that revealed in Figure 15. The average forced outage rate over the study period was [redacted] percent, which is low by industry standards.

Figure 16: Outage Rate
January 2011 – March 2011

[redacted]

Finally, the correlations of the average outage rates to the VACAR price and the short-term sales price are shown in Figure 17.

Figure 17: Correlation of Average Outage Rates with Wholesale Energy Prices
January 2011 – March 2011

	Correlation with VACAR Index	Correlation with Duke Real-Time Sales Prices
Planned Outages	-52%	-21%
Unplanned Outages	53%	62%

Figure 17 reports both planned and unplanned outages. The unplanned ones are the most important from a market power perspective. Planned outages are expected and generally are scheduled in off-peak periods. Unplanned outages can occur during peak times. The negative correlations of the planned outage rate with VACAR index price and Duke real-time sales prices are expected given that planned outages are typically scheduled during off-peak periods when prices are lower. The correlations of the unplanned outage rate with Duke real-time prices and the VACAR index are positive. This is driven by the generation outages described above. The outages are found to be justified even though they may have contributed to high Duke sales prices.

Generation dispatch and availability on February 21 and 23 did not contribute to the curtailments noted in the prior analysis on Sales and Purchases.

Based on these results, we find no evidence that generation outages were associated with anticompetitive conduct.

C. Analysis of Transmission Availability

Transmission outages are reviewed in order to determine whether they limit market access and, if so, whether they are justified. There were 44 transmission outages that affected power flows on elements at 100 kV and higher during the period of study. We reviewed these outages with a focus on conditions that would have reduced transfer capability on the key paths when the TTC was reduced and the ATC was near zero as shown in Figure 7 through Figure 10. Based on our review of the shift factors of the equipment in outage to the limiting contingencies for setting TTCs, we found the following outages to be of interest.

- [redacted] This outage was one contributor to a TTC limitation on "Duke to SOCO" which led to TSR refusals and curtailments on January 13.
- [redacted] This outage was one contributor to TTC limitation on "Duke to PJM" which led to multiple TSR refusals.
- [redacted] The outage was caused by [redacted]

[redacted]

Through our investigation of these outages, based on a review of documentation and logs, we find these outages to be reasonable and justified. In addition, Duke transmission outages on [redacted] not contribute to the curtailments noted in the prior analysis on Sales and Purchases. Accordingly, our analysis of transmission availability did not indicate that Duke reduced market access through unjustified transmission outages.